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Refinery Heater Screening Study

Acurex Corp, Mountain View, CA Energy and Environmental Div

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Refinery Heater Screening Study

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This screening study provides a general background description of refinery heaters, an inventory of their application, and estimates of SO_X, NO_X, and HC_X emissions.

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Refinery Heater Screening Study

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FOREWORD

This report presents the results of a screening study to characterize emissions from petroleum refinery heaters and techniques for controlling these emissions. The study was performed by the Energy and Environmental Division of Acurex Corporation under Contract No. 68-02-2611 to the U.S. Environmental Protection Agency (EPA).

The EPA Project Officer was Ms. Kerri Brothers of the Chemical and Petroleum Branch, OAQPS. The Acurex Program Manager was Dr. Larry Cooper, and Mr. Steven Ayraud was the Project Engineer. Mr. Richard Schreiber acted as Assigned Reviewer. The study was performed during the months of June through September 1978.

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SI UNITS CONVERSION FACTORS

The following are conversion factors for the SI units used in this report.

SI Units	Multiplied by	Yields English Unit
MW	3.4	Btu/hr
liter	6.2×10^{-3}	bbl
m^2/s	10^6	centistokes
N/m^2	1.45×10^{-4}	psia
m^3	35.3	ft^3
ng/J	2.32×10^{-3}	$lb/10^6$ Btu
kg/yr	1.1×10^{-3}	tons/yr
kg/100 m^3	5.46×10^5	grain/100 ft^3

SECTION 1

INTRODUCTION

Recognizing the need for information on refinery heaters, the Environmental Protection Agency authorized this screening study. The data compiled will be used by the EPA as background information in the current investigation of the need to control emissions from this type of equipment.

The purpose of this study is to develop refinery heater equipment, emission, and controls inventories, and to suggest plans for future study based on data gaps. The specific areas covered in this report include:

- Inventories of refinery heater population, construction, fuel consumption and emission controls
- Compilation of all existing heater emissions data with associated construction information
- Development of emissions factors based on the data
- Estimation of refinery heater emissions
- Evaluation of heater emissions controls
- Formulation of a test program to supplement and verify existing emissions data and evaluate control technology

During the term of this project was (Summer 1978), an American Petroleum Institute (API) study was nearing completion by KVB, Inc., which apparently covers much of the same material. The API study, tentatively scheduled for release in late 1978, should supplement the present study.

SECTION 2

INTRODUCTION TO PROCESS HEATERS IN THE PETROLEUM INDUSTRY

2.1 PETROLEUM REFINING

Petroleum is commonly refined by distillation separation into intermediate feedstocks and products. The intermediate feedstocks require heating and thermal or catalytic cracking before separating the desired products. Some of the major processes of a modern refinery are described below.

Crude Distillation

Heated crude oil flows through a fractionating column which is tapped at several points to allow continuous removal of the various boiling fractions. The resulting residuum may be processed by vacuum distillation. After distillation, the products serve as feedstocks for downstream processing as well as some final products.

Thermal Cracking

This process includes visbreaking and coking as well as regular thermal cracking. In each of these operations, heavy oil fractions are broken into lighter fractions, such as domestic heating oil and catalytic cracking stock, by the action of heat and pressure.

Catalytic Cracking

This process, like thermal cracking, breaks heavy fractions into lighter fractions and is probably the key process for producing large

volumes of high octane gasoline stocks, furnace oils, and other useful middle distillates. Catalysts operate at lower temperatures and pressures than those of thermal cracking.

Catalytic Reforming

Reforming is a process of molecular rearrangement to convert low octane feedstocks to high octane gasoline blending stock, or to produce aromatics for petrochemical uses. Multireactor, fixed bed, catalytic processes have almost completely replaced the older thermal processes.

Hydrotreating

This family of processes can remove sulfur compounds, odor, color, gum-forming materials, and other impurities from a wide variety of petroleum fractions in the presence of hydrogen. It is one of the most varied and rapidly growing refinery processes.

2.2 PROCESS HEATING

Total refinery energy consumption amounts to about 10 percent of the crude throughput. Much of this energy is consumed in refinery heaters, which transfer heat released from fuel combustion to petroleum derivatives contained in large, widely spaced tubes.

Industry identifies these heaters with such names as process heater, furnace, process furnace, and direct fired heater, all of which are interchangeable.

Refinery heater size is defined in terms of its design heat release capability, or duty. Duties range from about 0.14 MW (0.5×10^6 Btu/hr) heat input for small specialty units to about 288 MW (10^9 Btu/hr) heat input for superproject facilities. The majority of fired heater installations fall within the 10 MW to 100 MW (34 to 340×10^6 Btu/hr) heat input range.

Process industry requirements for refinery heaters are divided into a half dozen general service categories which are described below (for more information, see Reference 2).

Distillation Column Reboilers

This is normally considered one of the mildest and least critical of refinery heater applications. The charge stock taken from a distillation column is a recirculating liquid that is partially vaporized in the fired heater.

Fractionating Column Feed Preheaters

These heaters are involved in a number of process operations. The charge stock is sent to the heater where the fluid temperature is raised to achieve partial vaporization. The stock then passes to a fractionating column.

Reactor Feed Preheaters

Heaters in this application raise the charge stock temperature to control reactions in an adjoining reactor vessel.

Heat Supplied to Heat Transfer Media

Many plants furnish heat to individual users via an intermediate heat transfer medium. A heater elevates temperature of the recirculatory medium, which is typically a heating oil or Dowtherm.

Fired Reactors

In this category are heaters in which a chemical reaction occurs within the tube coil. These units represent the fired heater industry's most sophisticated technology. Steam cracking is the best example of the use of fired reactors.

SECTION 3

EQUIPMENT AND FUEL CONSUMPTION INVENTORY

3.1 INTRODUCTION

The original intention of this section was to provide a detailed inventory of refinery heaters broken into several design classifications. These classifications were to include draft type, burner type, heater configuration, heater size, process, emissions controls, and fuel type and consumption.

However, literature surveys and conversations with industry representatives showed that design classifications of heaters vary extremely, with few trends within the industry. This is largely due to the fact that heaters are usually custom designed for individual refineries. Therefore, the inventory for heater configuration, burner type and draft type is limited to a general description of equipment and current and future design trends.

We originally intended to use the National Emissions Data System (NEDS) to provide the data base for many of the remaining items to be inventoried. NEDS consists of a computerized source/emissions data bank located at EPA in Research Triangle Park, North Carolina.

NEDS maintains detailed emissions, fuel consumption, size, emissions control technology and location information for all major emission sources in the country. By requesting a point source listing for

source classification code 306001, every entry in the data bank for process heaters in the petroleum industry can be retrieved.

After closely examining the resulting data and from conversations with regional EPA personnel, the following problems using NEDS as a data base for the inventory were discovered:

- The data in NEDS are incomplete and do not represent a sufficiently large portion of the refinery heater population
- Much of the data had not been updated since original entry in 1970
- Some entries represent multiple heaters, and sometimes boilers, and provide no information on the number or identity of the sources

These problems limited our use of the NEDS data and alternate methods were chosen for completing the inventories.

Information in this section is organized as follows:

- Population Inventory -- estimates of the number of refinery heaters for each state
- Process Inventory -- percentages of energy used in refinery processes for each state
- Heater Construction -- discussions of equipment and trends in heater configuration, draft type and burner type
- Heater Size Inventory -- national percentages of fuel consumption and numbers of heaters for three size ranges
- Fuel Type and Consumption Inventory -- refinery heater 1976 fuel consumption by state (or state group)
- Control Technology -- types and numbers of heater emissions controls installed in each state

3.2 REFINERY HEATER POPULATION INVENTORY

As mentioned earlier, although NEDS data were incomplete in some cases, entries for several refineries were felt to be reasonably complete. Figure 1 represents the number of heaters for these entries plotted against refinery crude capacity. The resulting graph shows a rough relationship between crude capacity and numbers of refinery heaters. The relationship seems to be the most accurate for refinery crude capacities less than 4.85×10^7 liters/cd (300,000 bbl/cd).

Using refinery crude capacity information published in the Oil and Gas Journal (Reference 3) for January 1, 1978, Table 1 was developed. This table lists the number of heaters for each state based on individual refinery crude capacity and the relationship developed in Figure 1.

3.3 PROCESS INVENTORY

Since petroleum refining processes vary widely, identifying numbers of heaters by process application is very difficult. Therefore, the approach taken here presents energy consumption percentages per process to indicate applications with significant fuel consumption and emissions.

Process heating energy consumption estimates were developed using correlations of energy consumption per barrel of feed from the Oil and Gas Journal (Reference 4). Then, using state production information by process (Reference 3), Table 2 was developed.

National results from this table indicate that nearly one-third of the process heating energy consumption takes place in crude distillation. Nearly three-quarters of the total consumption is used for crude distillation, vacuum distillation, catalytic cracking (i.e., feed preheating) and catalytic reforming.

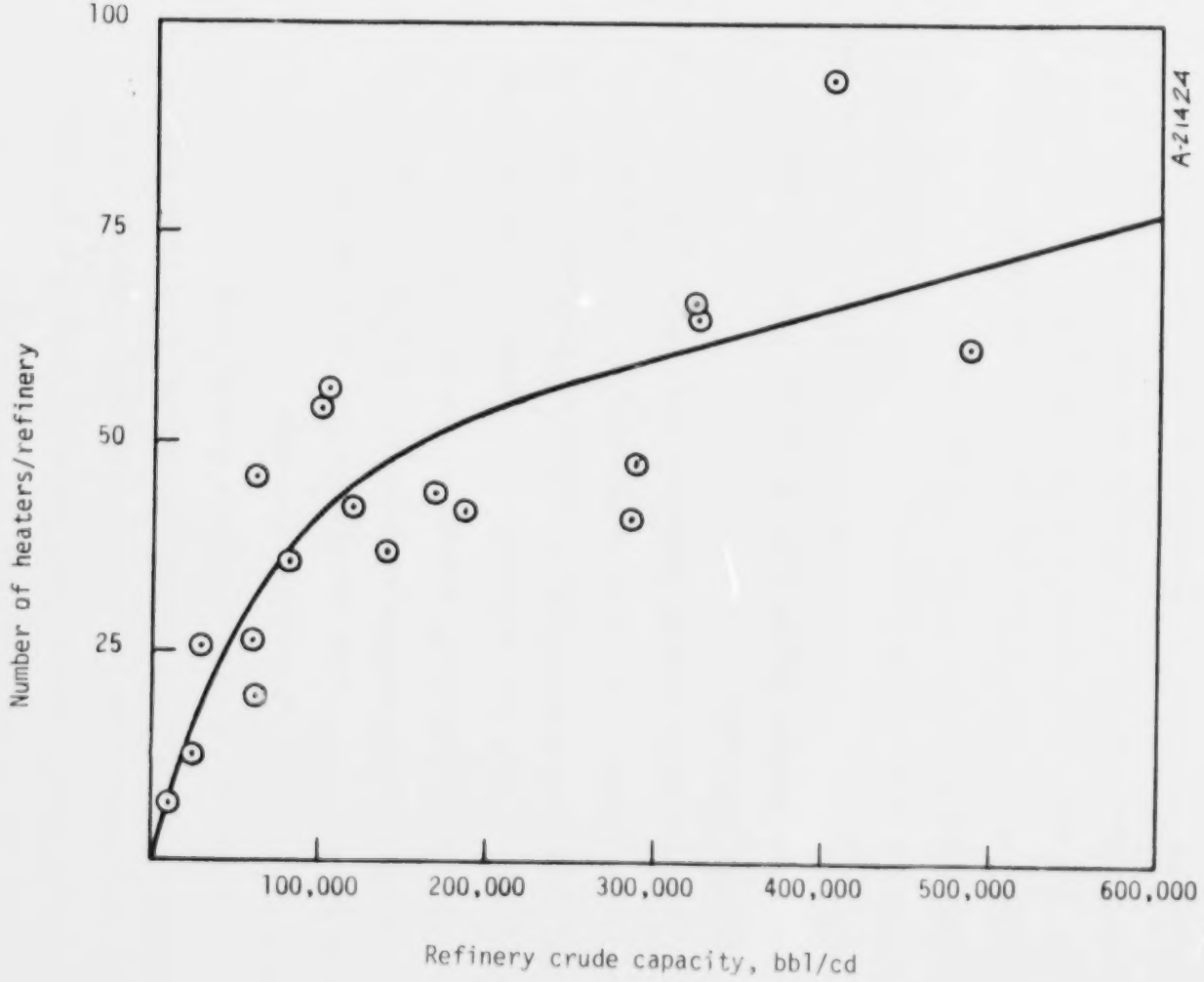

Figure 1. Number of heaters per refinery versus refinery crude capacity.

TABLE 1. REFINERY HEATER INVENTORY BY STATE

State	No. of Heaters
Alabama	73
Alaska	58
Arizona	6
Arkansas	41
California	893
Colorado	41
Delaware	49
Florida	4
Georgia	13
Hawaii	56
Illinois	388
Indiana	157
Kansas	242
Kentucky	67
Louisiana	590
Maryland	17
Michigan	86
Minnesota	93
Mississippi	89
Missouri	42
Montana	88
Nebraska	3
Nevada	1
New Hampshire	8
New Jersey	190
New Mexico	67
New York	57
North Carolina	10
North Dakota	34
Ohio	239
Oklahoma	280
Oregon	10
Pennsylvania	258
Tennessee	25
Texas	1393
Utah	95
Virginia	29
Washington	174
West Virginia	16
Wisconsin	25
Wyoming	126
	6133

TABLE 2. PERCENTAGES OF HEATING ENERGY REQUIRED PER PROCESS BY STATE (Reference 4)

State	Crude Distillation	Vacuum Distillation	Thermal Operations					Cat. Cracking	Cat. Reforming	Cat. Hydrocracking			Cat. Hydrorefining	Cat. Hydrotreating	Alkylation	Aromatics/Isomerization			Lube Manuf.	Asphalt, Blend, Load
			1. Gas-Oil Cracking	2. Visbreaking	3. Fluid Coking	4. Delayed Coking	5. Other (est.)			1. Distillate Upgrading	2. Residual Upgrading	3. Other (est.)				1. BTX; Hydrodeakylation	2. Cyclohexane, C_6 Feed	Polymerization		
Alabama	65	12							15				3	5						<0.5
Alaska	82								15					3						<0.5
Arizona	62	38																		1
Arkansas	33	18							9					4	7				19	<0.5
California	28	16	<.5	2	2	8	1	8	14	8		1	2	5	4	<.5	<.5		2	<0.5
Colorado	38	8		16				14	19				5					1		<0.5
Delaware	22	16			15			12	19		3			9	4	<.5				
Florida	55	45																		
Georgia	97																			3
Hawaii	51	8						11	15					4	7	4				<0.5
Illinois	27	11	1			7		13	21				1	6	8	1			1	<0.5
Indiana	32	18				4		13	17					7	6	<.5			3	<0.5
Kansas	29	11	1			7		13	20	<.5			2	6	9	<.5	<.5		3	<0.5
Kentucky	27	16		1				12	15				4	7	3	6	3		7	<0.5
Louisiana	31	12	<.5	<.5		5	2	11	18	3			2	4	7	2		<0.5	4	<0.5
Maryland	64	34																		2
Michigan	38	10						16	24				3	4	5					<0.5
Minnesota	30	20				9		12	13				5	6	6			<0.5		<0.5
Mississippi	28	16				2		7	24	13		1	3	3	3	3				<0.5
Missouri	31	14			10			17	14					10	5					<0.5
Montana	29	11	1		3			13	23	2			1	9	6		1			<0.5

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TABLE 2. Concluded

State	Crude Distillation	Vacuum Distillation	Thermal Operations	1. Gas-Oil Cracking	2. Visbreaking	3. Fluid Coking	4. Delayed Coking	5. Other (est.)	Cat. Cracking	Cat. Reforming	Cat. Hydrocracking	1. Distillate Upgrading	2. Residual Upgrading	3. Other (est.)	Cat. Hydrorefining	Cat. Hydrotreating	Alkylation	Aromatics/Isomerization	1. BTX; Hydrodeakylation	2. Cyclohexane, C_6 Feed	Polymerization	Lube Manuf.	Asphalt, Blend, Load
Nebraska	40	21		16					23														
Nevada	100																						
N. Hampshire	100																						
N. Jersey	30	19			1		3		14	17					3	8	3					2	<0.5
N. Mexico	50	7		2					9	24						2	5						<0.5
N. York	31	15							15	20					3	7	5		5				<0.5
N. Carolina	100																						
N. Dakota	42			2					26	17						4	6					2	
Ohio	27	11					3		12	22		3		6	1	4	6		5			1	<0.5
Oklahoma	28	11		1			7		13	19		1			1	5	8		1	1	<0.5	6	<0.5
Oregon	44	55																					1
Pennsylvania	27	14							9	22		2		2	3	6	4		2			8	<0.5
Tennessee	35	14							11	24						5	11						<0.5
Texas	27	11		2	<.5		3	<.5	10	20		2			2	7	5		5	1		5	<0.5
Utah	38	12				5			16	14		1			1	4	8			1			<0.5
Virginia	26	17					20		17	14					7								
Washington	27	13			1		6		9	23		6			1	7	6			<0.5			<0.5
W. Virginia	18	9								17					2	4							50
Wisconsin	36	19							9	23					3	4	5						1
Wyoming	35	15						2	15	17					2	6	5			<0.5		2	<0.5
Nation	29	13		1	1	<0.5	4	<0.5	11	19	3	<0.5	<0.5		2	6	5		2	<0.5	<0.5	3	T-1374 <0.5

3.4 REFINERY HEATER CONSTRUCTION

Since layout, design and construction of refinery heaters varies greatly, few construction trends have been established. Individual heater manufacturers may have their own design philosophies, but process heating specifications sent to two different manufacturers by a refinery can result in totally different designs. As a consequence, this section is limited to a discussion of equipment types and design trends.

3.4.1 Heater Configuration

As mentioned previously, most heaters, especially those with large capacity, are custom designed (in-house or by an outside contractor) for the specific requirements of the refinery and, therefore, consist of a number of shapes and sizes. However, the basic heater design involves a radiant section and a convection section.

The radiant section consists of the combustion chamber of the heater. This chamber includes the radiant tube coils and the burners. In this area, much of the heating is accomplished by radiation from the flame, although convection currents within the heater do account for a portion of the total heat absorbed.

In addition to the radiant section, most modern heaters include a separate convection section. The residual heat of the flue gas is recovered in this section by mounting convection coils in the flue. This heat is used for generating steam or for preheating the charge stock.

The principal classification of heaters relates to the orientation of the heating coil in the radiant section (i.e., whether the tubes are horizontal or vertical). Figure 2 illustrates some of the major designs listed below (Reference 2).

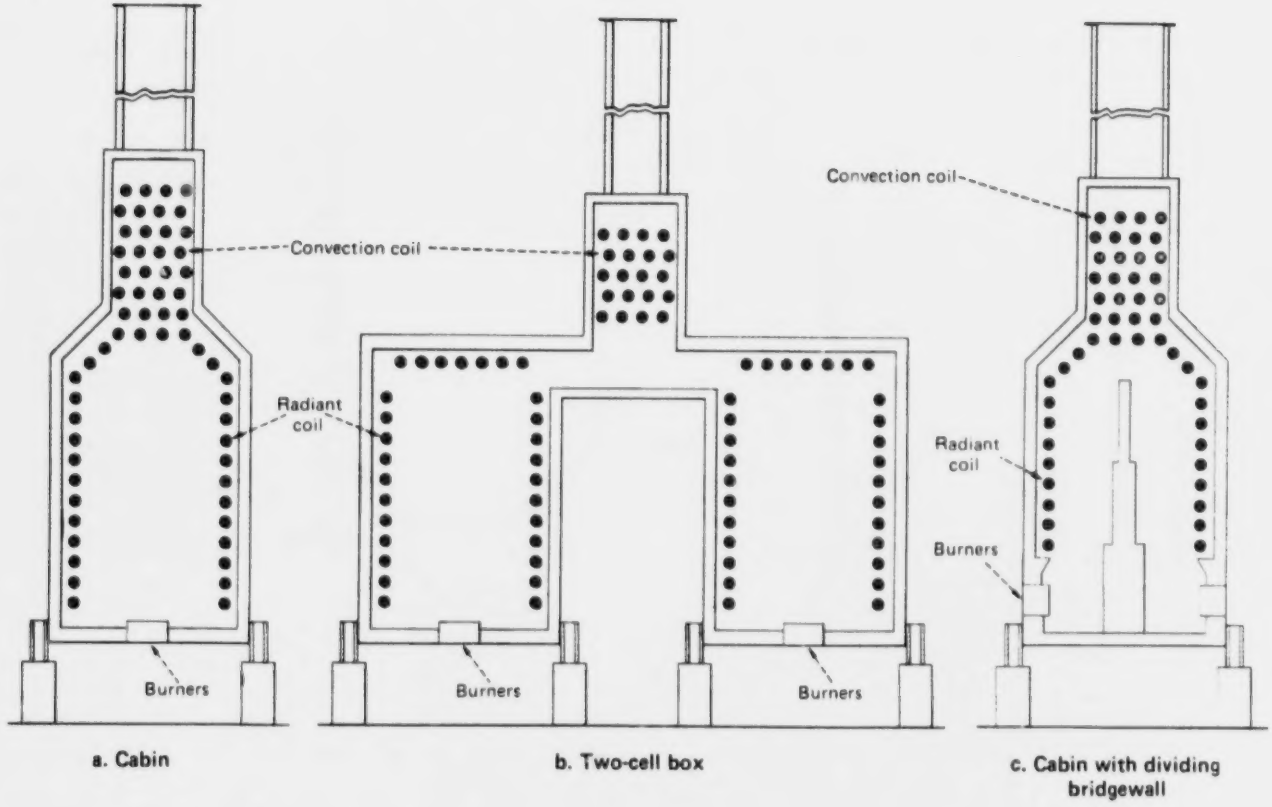
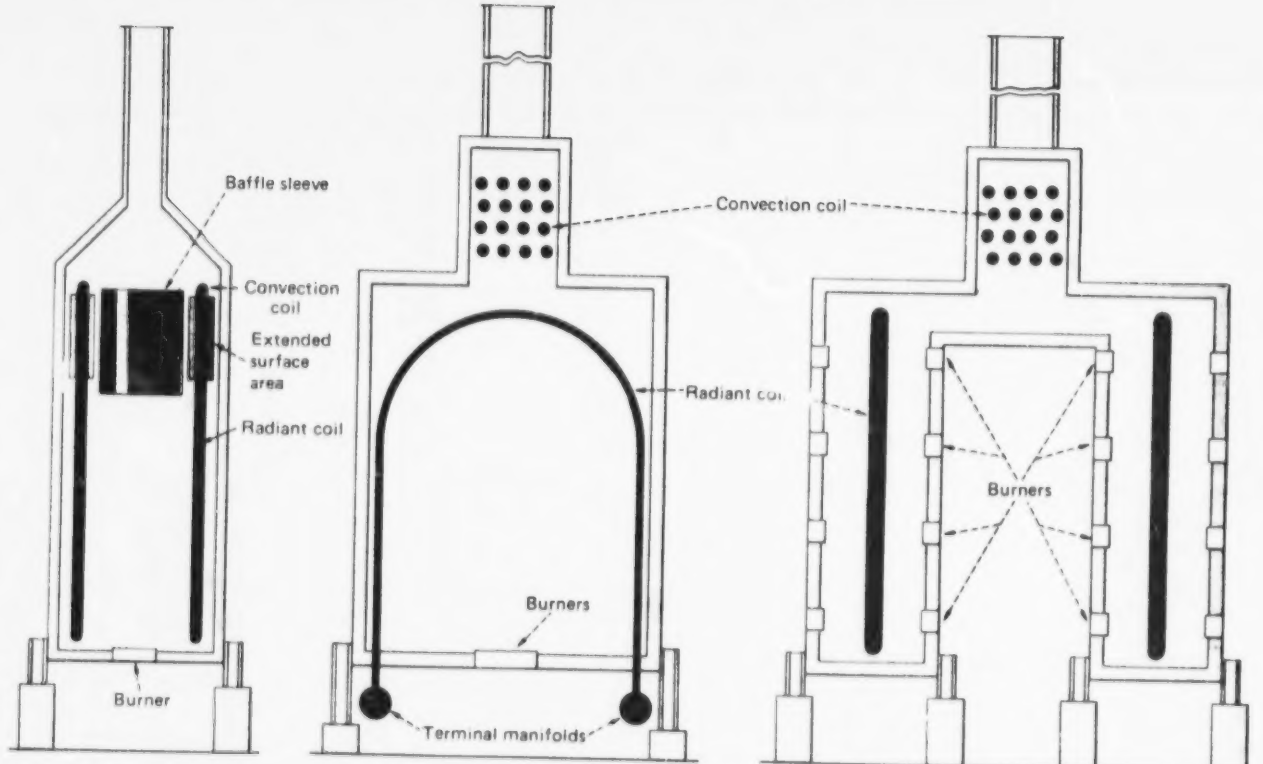


Figure 2. Basic refinery heater designs (Reference 2).



d. Vertical-cylindrical with integral convection section

e. Arbor or wicket type

f. Vertical-tube, single-row, double-fired

Figure 2. Concluded.

Horizontal Tube Cabin

The radiant section tube coils of these heaters are arranged horizontally to line the walls of the combustion chamber and the sloping roof. Normally, the tubes are fired vertically from the floor. Duties run 3 MW to 30 MW (10 to 100 x 10^6 Btu/hr) heat input (see Figure 2(a)).

Two-Cell Horizontal Tube Box

Here two combustion chambers with separate banks of horizontal tubes utilize the same convection section. Typical duties range from 30 MW to 73 MW (100 to 250 x 10^6 Btu/hr) heat input (see Figure 2(b)).

Horizontal Tube Cabin with Dividing Bridgewall

In this application, a dividing bridgewall between the combustion chamber sections allows individual firing control. Available options permit horizontal firing with sidewall mounted burners (as shown), or vertical firing from the floor along both sides of the bridgewall. A typical duty range for this design is 1.5 MW to 15 MW (5 to 50 x 10^6 Btu/hr) heat input (see Figure 2(c)).

End Fired Horizontal Tube Box, with Side Mounted Convection Section

Here the radiant section tube coil is placed horizontally along the sidewalls and roof of the combustion chamber. The convection section coil is arranged as a horizontal bank of tubes positioned alongside the chamber. The unit is horizontally fired from burners mounted on the end wall. Duties range from 15 MW to 59 MW (50 to 200 x 10^6 Btu/hr) heat input.

Horizontal Tube, Double Fired

Horizontal radiant tubes are arranged in a single row and are fired from both sides to uniformly distribute heat transfer rates around the tube circumference. Such heaters are normally fired vertically from the

floor. Duties range from 60 MW to 15 MW (20 to 50 x 10^6 Btu/hr) heat input.

End Fired Horizontal Tube Box

This design is similar to the horizontal tube cabin but with horizontal firing from burners mounted on the end walls. Duties range from 1.5 MW to 15 MW (5 to 50 x 10^6 Btu/hr) heat input.

Vertical Cylindrical, all Radiant

Here the tube coil is placed vertically along the walls of the combustion chamber. Firing is also vertical, from the floor of the heater. Typical duties are 0.15 MW to 6 MW (0.5 to 20 x 10^6 Btu/hr) heat input.

Vertical Cylindrical, Helical Coil

In these units, the coil is arranged helically along the walls of the combustion chamber, and firing is vertical from the floor. Heating duties range from 0.15 MW to 6 MW (0.5 to 20 x 10^6 Btu/hr) heat input.

Vertical Cylindrical, with Integral Convection

As with previous types, this design is vertically fired from the floor, with its tube coil installed in a vertical arrangement along the walls. Added surface area on the upper parts of each tube helps to promote convection heating. Typical duty for this design is 3 MW to 30 MW (10 to 100 x 10^6 Btu/hr) heat input (see Figure 2(d)).

Arbor or Wicket

This is a specialty design in which the radiant heating surface is provided by U-shaped tubes. This design is often employed in the catalytic reformer charge heater and in various reheat services. Typical duties are about 15 MW to 29 MW (50 to 100 x 10^6 Btu/hr) heat input (see Figure 2(e)).

Vertical Tube, Double Fired

In these units, vertical radiant tubes are arranged in a single row in each combustion cell (there are often two cells) and are fired from both sides of the row. Such an arrangement yields a highly uniform distribution of heat transfer rates about the tube circumference. Multilevel sidewall firing units are often employed in fired reactor services and in critical reactor feed heating services, where maximum control of the heat flux profile is needed. Duties range from 6 MW to 37 MW (20 to 125 x 10^6 Btu/hr) heat input (see Figure 2(f)).

Generally, past configuration trends have been toward horizontal box units for large capacities and vertical cylindrical units for smaller capacities. Future trends are toward more vertical cylindrical designs because of higher efficiencies and reduced space requirements (Reference 4).

3.4.2 Draft Types

Another major classification of heaters is their method of combustion air supply and flue gas removal.

The majority of fired heater installations are natural draft types. Specifically, about 90 percent of all gas-fired heaters and 76 percent of all oil-fired heaters are natural draft (Reference 6). These heaters utilize the buoyancy of the hot flue gas to create "draft" (less than atmospheric pressure) which induces flow of air into the combustion chamber and out the stack.

Instead of a stack, some heaters use an induced draft fan to maintain a negative pressure (relative to ambient) to induce combustion airflow and remove the flue gas.

A forced draft heater supplies combustion air under positive pressure by using a forced draft fan. In this application, the combustion chamber is still maintained under negative pressure, and the flue gas is removed by the stack effect.

A forced draft/induced draft (balanced draft) heater uses a forced draft fan to supply combustion air under positive pressure. An induced draft fan maintains the combustion chamber and all other parts of the fired heater under negative pressure and removes the flue gas.

Many balanced draft heaters incorporate an air preheater to exchange heat from the hot flue gas to the inlet air. This increases combustion temperature, and therefore, usually increases efficiency.

Currently, natural draf. neaters account for 90 percent of the gas-fired fuel consumption and 76 percent of the oil-fired fuel consumption (Reference 6). Future designs should tend toward mechanical draft construction since combustion can be better controlled, which usually results in more efficient operation.

3.4.3 Burner Types

This subsection describes the design features of refinery heater burners. There are so many variations in burner design that discussing each separately would be beyond the scope of this report. Reference 7 contains more detailed information on this subject.

A burner consists primarily of a means of metering the two reactants, oxygen and fuel, and a means of mixing before and concurrently with ignition. Gas-fired burners tend to be much simpler in design and operation than oil-fired burners.

Burners designed for gaseous fuel only are classified into two basic categories -- premix inspirating and raw gas burning.

The premix burner relies on kinetic energy (from expansion of fuel gas through an orifice) to inspirate and mix combustion air prior to ignition at the burner tip. Approximately 50 to 60 percent of the combustion air is inspirated as primary air into the burner ahead of the ignition point. Secondary air registers then provide the remainder of the air necessary for complete combustion.

The nozzle-mixing, raw gas burner receives fuel gas from the gas manifold without any premixing of combustion air. The gas is then burned at a tip equipped with a series of small ports (see Figure 3(a)).

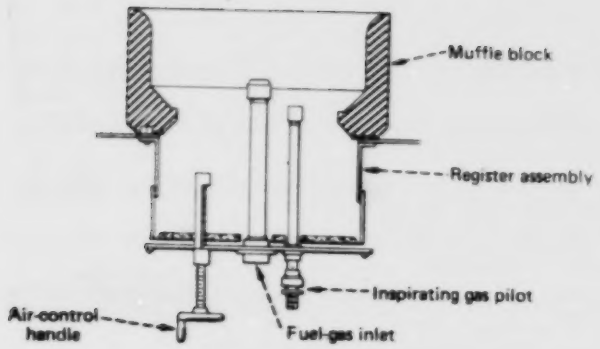
Special measures must be used for burning fuel oil, since mixing of fuel and combustion air must occur in the gaseous phase. To accomplish this, all liquid fuel burners use atomizing devices to break up the liquid into small droplets.

Oil burners in refinery heaters almost always utilize steam as the atomizing medium (Reference 7). Steam and oil are injected separately into a mixing chamber ahead of the burner tip, where the steam mixes with the oil. The steam and the finely dispersed oil then issue through a series of orifices into the turbulent air stream.

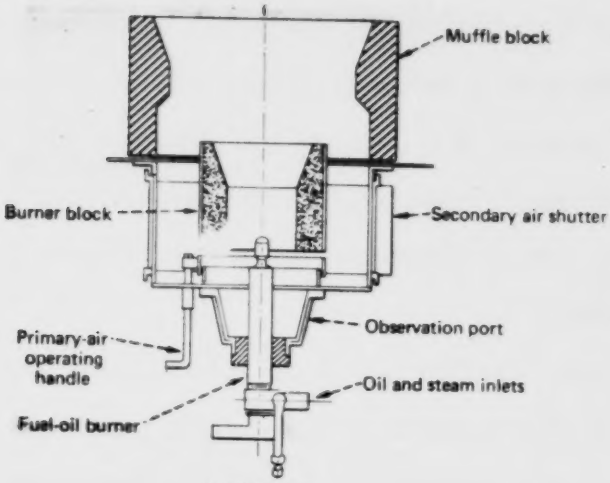
For proper combustion of oil, the following important requirements should be met (Reference 7):

1. The oil must be heated high enough that its viscosity is not greater than 4.2×10^{-5} m^2/S (42 centistokes)
2. Oil pressure must be held constant, typically at about 620×10^3 N/m^2 (90 psia)
3. The steam delivered at the burner must be dry (unsaturated)

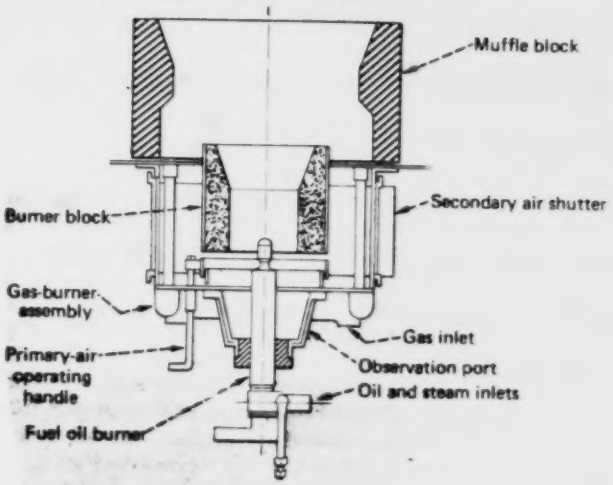
Figure 3(b) depicts a typical steam-atomized oil burner.



a. Raw-gas burner



b. Oil burner



c. Combination oil and gas burner

Figure 3. Basic refinery heater burner designs (Reference 7).

For those instances when oil must be burned and steam is not available, air or mechanical atomization can be used. The operating requirements of air-atomized oil burners are similar to those of steam-atomized ones, although a slightly higher oil temperature may be needed to compensate for the cooling effect of the atomizing air.

In mechanically-atomized burners, the fuel oil is given a strong whirling action before its release through the burner tip. Oil temperature and viscosity ranges are similar to those needed for steam atomization.

To provide for fuel switching, which often takes place in a refinery, combination burners (Figure 3(c)) designed to burn any combination of oil or gas are used. Typically, these burners feature a double block design in which a single oil gun is centered in an array of gas nozzles.

Gas firing in the newer combination burners is almost always accomplished with raw gas nozzles. Separate register adjustments allow independent control of primary air for oil combustion, and secondary air for fuel gas combustion.

As seen in Figures 2 and 3, the number and configuration of heater burners can vary greatly. For processes which require critical heating distribution -- reforming, for example -- a natural draft heater may have several hundred burners. Generally, forced draft heaters tend to have a small number of large capacity burners and natural draft heaters have a large number of small capacity burners.

3.4.4 Differences Between Boilers and Heaters

Heaters and steam boilers are often lumped together when considering combustion equipment in refineries, but there are significant differences between the two equipment types.

The flow through heaters is generally a single pass through large diameter tubes. The tubes are widely spaced, and furnace refractory walls just behind the tube bank reradiate heat to the side of the tubes away from the flame.

Boiler tubes have evolved quite differently. They are generally small tubes in a finned and welded construction. Flow consists of many parallel passes. Heating in a boiler is a relatively concentrated, intense process. Burners tend to be closely spaced and of large capacity. Mechanical draft is almost always used, as opposed to natural draft burners commonly used in heaters. Because of problems with tube coking in heaters, boiler burners are of smaller capacity than heater burners resulting in less concentrated heating. They are designed to form round, conical, or flat flames to produce the proper heat distribution.

3.5 HEATER SIZE INVENTORY

The only data base available for a heater size (i.e., maximum heat input) inventory is NEDS. As mentioned earlier, the NEDS information appears to be incomplete. For example, entries for Texas (a state with many refineries), include virtually no heater size information.

As a consequence, it was decided to concentrate on developing a national refinery heater size inventory which reports percentages of heaters and fuel consumption for three heat input size ranges: <15 MW (50×10^6 Btu/hr), >15 MW (50×10^6 Btu/hr) and <44 MW (150×10^6 Btu/hr), and >44 MW (150×10^6 Btu/hr).

The results are presented in Table 3 and indicate that the majority of refinery heaters fall within the "small" (<15 MW) size range, while fuel consumption is concentrated in the larger size ranges (>15 MW). Also, there is a trend toward more oil firing than gas firing in the large (>44 MW) size ranges.

3.6 HEATER FUEL TYPE AND CONSUMPTION INVENTORY

Refinery heaters are likely to be fired with natural gas and a variety of refinery byproduct fuels, both gaseous and liquid. These fuels can be the least salable refinery products (such as heavy residual oils and high sulfur-bearing gas). The gaseous fuels are usually mixtures obtained during the refinery processes which are not marketed or further processed. They can contain appreciable amounts of sulfur, hydrogen, carbon monoxide and higher molecular weight hydrocarbons.

The highest viscosity oil fuels produced at a refinery are commonly used within the refinery itself. Residual fuel oils have traditionally been difficult to market. Consequently, refinery operators prefer to burn as much of this fuel as possible in their own equipment.

Fuel switching in heaters is a common practice in refineries and often occurs on a seasonal basis. During the winter, when demand for natural gas for residential heating is high, there is a tendency toward more oil firing. During the summer, emissions restrictions can sometimes force the switching from oil-fired operation to "cleaner" burning fuels.

For the future, there are conflicting trends in the type of fuel consumption, thus making fuel projections difficult. Scarcity of natural gas may force increased oil-fired operation, but emissions regulations for sulfur-bearing oil would require extensive emissions controls.

TABLE 3. NATIONAL REFINERY HEATER INVENTORY BY SIZE RANGE

Classification	<15 MW (50 x 10^6 Btu/hr)	>15 MW (50 x 10^6 Btu/hr) and <44 MW (150 x 10^6 Btu/hr)	>44 MW (150 x 10^6Btu/hr)
Oil-Fired Heaters	54%	34%	12%
Oil-Fired Heater Fuel Consumption	12%	31%	57%
Gas-Fired Heaters	63%	27%	10%
Gas-Fired Heater Fuel Consumption	25%	32%	43%

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The refinery heater fuel consumption inventory is presented in Table 4. Also presented in this table is the crude capacity for each state (or state group). The fuel consumption information was developed from the Energy Data Reports published by the Department of Energy for 1976 (Reference 8). These reports give fuel consumption for all purposes at refineries in the United States on a state-by-state (or state group) basis.

Since the total refinery fuel consumption includes boiler consumption in addition to process heater requirements, these figures have been modified to reflect only heater consumption. W. L. Nelson in the Oil and Gas Journal has estimated that process heating accounts for approximately 80 percent of the total heating in a refinery (Reference 9). Consequently, Table 4 represents values from the Energy Data Reports reduced by 20 percent.

3.7 CONTROL TECHNOLOGY INVENTORY

Table 5 lists refinery heater emissions control installations by state. This information has been obtained from NEDS data.

Although the NEDS system is somewhat incomplete (between 50 and 75 percent coverage for the country), the results of this table indicate that very few emission controls are in use (particularly few NO_x controls). This is the result of few emission restrictions on refinery heaters.

TABLE 4. CRUDE CAPACITY AND PROCESS HEATER ENERGY CONSUMPTION FOR U.S. REFINERIES -- 1976

Area	Crude Capacity	Process Heater Consumption				
		Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gas	Natural Gas	Refinery Gas
	10^6 liters/cd	10^6 liters/cd	10^6 liters/cd	10^6 liters/cd	$10^6 m^3$/cd	$10^6 m^3$/cd
Arkansas	9.7	4.1	11	1	116	77
California, Washington, Oregon,	391.6	96.9	750	454	2703	4683
Hawaii and Alaska, Colorado	9.9	2.4	16	6.7	72	88
Delaware, MA, NH, RI, VA	30.7	25.4	42	44	20	451
Georgia, NC, SC, FL	3.8	9.8	7	--	18	--
Illinois	187.2	28.1	855	229	221	2058
Indiana	89.3	1.4	582	17	36	1016
Kansas	71.8	C.1	182	43	637	809
Kentucky, Tennessee	33.1	0.1	178	22	105	318
Louisiana	279.0	115.5	305	69	2089	2789
Maryland	4.5	14.9	21			--
Michigan	23.4	--	96	7	61	139
MN, WI, ND	51.1	1.3	210	21	3	396
Mississippi, Alabama	60.4	3.1	32	37	5	712
Missouri, Nebraska	17.8	0.1	75	0.8	0.1	241
Montana	24.9	--	96	18	105	264
New Jersey	85.8	--	666	58	183	734
New Mexico	16.6	--	10	20	109	61
New York	17.7	--	134	23		156
Ohio	93.9	5.5	250	79	277	1045
Oklahoma	86.9	14.6	7	13	1139	1032
Pennsylvania	120.5	53.8	959	0.5	440	1290
Texas	631.2	186.6	261	41	11,563	7287
Utah	24.2	5.5	78	25	72	214
West Virginia	3.1	7.1	50	--	22	36
Wyoming	29.8	0.5	127	11	280	227
Total United States	2399	590	6001	1240	20,818	26,121
Energy Equivalent - 10^{12} J		22,789	250,377	32,996	791,876	963,460
Percent of Energy Consumption		1.1	12.2	1.6	38.4	46.7

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TABLE 5. STATE EMISSIONS CONTROL TECHNOLOGY INVENTORY

State	Control	Pollutant Species[a]	Technology	Number of Installation
Alabama	Primary	SO_x	Wet Scrubber	1
Alaska	Primary	HC	Vapor Recovery	3
	Secondary	HC	Flaring 1	
California	Primary	HC	Gas Scrubber	1
Illinois	Primary	Part.	Centrifugal Collector	1
Indiana	Primary	Part.	Centrifugal Collector	1
Kansas	Primary	Part.	Centrifugal Collector	1
	Primary	HC	Afterburner	1
Louisiana	Primary	Part.	Centrifugal Collector	2
	Primary	SO_x	Gas Scrubber	1
	Primary	HC	Gas Absorption Column	1
	Primary	SO_x	Sulfur Plant	35
	Primary	SO_x	Gas Absorption Column	9
	Primary	CO	Afterburner	1
Maryland	Primary	Part.	Gravity Collector	1
Missouri	Primary	Part.	Centrifugal Collector	1
North Dakota	Primary	Part.	Centrifugal Collector	2
Ohio	Primary	SO_x	Gas Absorption Column	7
Oklahoma	Primary	Part.	Gas Scrubber	8
	Primary	Part.	Catalytic Afterburner	1
	Primary	Part.	Electrostatic Precipitator	2
	Primary	SO_x	Sulfur Plant	8
	Secondary	SO_x	Direct Flame Afterburner	8
Pennsylvania	Primary	Part.	Electrostatic Precipitator	1
	Primary	SO_x	Catalytic Oxydation	1
Texas	Primary	SO_x	Sulfur Plant	1
Utah	Primary	HC	Flaring	2
Washington	Primary	HC	Direct Flame Afterburner	1
	Primary	CO	Direct Flame Afterburner	1
	Secondary	Part.	Direct Flame Afterburner	1

[a]Secondary controls are those which have been installed downstream from the primary controls.

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SECTION 4

REFINERY HEATER EMISSIONS INVENTORY

This section compiles all available refinery heater emissions data with associated design information. Emission factors are formulated from these data and compared with factors obtained from EPA AP-42 documents (Reference 10) and preliminary KVB values for the API/KVB report (Reference 6) mentioned in Section 1. These emission factors are used with fuel consumption values from Section 3 to estimate national emissions from refinery heaters.

The major pollutant species from combustion equipment are NO_x, CO, HC, SO_x and particulates. For heaters, NO_x and SO_x emissions are of most concern. The factors which influence formation of each of the pollutants are introduced below.

Oxides of Nitrogen (NO_x)

Oxides of nitrogen formed in combustion processes are due either to the thermal fixation of atmospheric nitrogen in the combustion air, which produces "thermal NO_x", or to the conversion of chemically bound nitrogen in the fuel, which produces "fuel NO_x". For natural gas and light distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil, crude oil and coal, the contribution from fuel-bound nitrogen can be significant and, in certain cases, predominant. Efforts in NO_x reduction focus on reducing oxygen levels,

reducing peak temperatures and reducing the time of fuel exposure in the areas of highest temperature.

Carbon Monoxide (CO) and Hydrocarbons (HC)

Carbon monoxide and hydrocarbon emissions in the exhaust gases of combustion systems result from incomplete fuel combustion. Conditions which can give rise to incomplete combustion include: insufficient O_2 availability, poor fuel/air mixing, cold wall flame impingement, reduced combustion temperature and decreased combustion gas residence time. Generally, a heater or boiler in reasonable operating condition will emit very little of these pollutants (Reference 15).

Particulate

Oil-fired stationary sources produce significant quantities of particulate. Particulate emissions from oil combustion can be composed of soot (condensed organic matter), cenospheres (hollow char particles) and ash (incombustible mineral matter). The conditions for reducing particulate formation (intense, high temperature flames as produced by high turbulence and rapid fuel/air mixing) are, unfortunately, not the conditions for suppressing NO_x formations. As a consequence, low NO_x combustion designs are often limited by particulate formation.

Oxides of Sulfur (SO_x)

Almost all of the sulfur present in fuels is converted to oxides of sulfur (SO_x) during combustion. In liquid hydrocarbon fuels, sulfur occurs in concentrations ranging from a trace to more than 5 percent by weight. Natural gas fuels contain very little sulfur, but refinery gas can contain appreciable amounts.

Table 6 lists the emissions data obtained for this report. Since NO_x control has historically been of primary concern, most of the available emissions data apply only to this pollutant.

Table 7 lists emission factors developed from Table 6. Too few data points and unacceptably large standard deviations indicate that confidence is low for many of these emission factors. More emissions data are needed to understand the spread in current data. Possible reasons for this spread are: the varying composition of refinery gas, heater combustion chamber cleanliness, and equipment condition (e.g., burner air registers were reported to be broken in some of the KVB tests).

As a comparison with other current emission factors, Tables 8(a) and 8(b) present refinery heater emission factors obtained from EPA AP-42 (Reference 10) documents and a recent study conducted by API/KVB (Reference 6). These latter numbers are tentative pending completion of the API/KVB study.

Comparing the NO_x emission factor for natural draft gas operation in Table 7 (the only factor with a reasonable amount of data and a reasonable standard deviation) with the corresponding API/KVB factor shows that the figure obtained for the present report is somewhat lower than the API/KVB data. On the other hand, the API/KVB emission factor for CO indicates negligible emissions which seems unreasonable when CO data is examined in Table 6. More data are needed to resolve this discrepancy.

The AP-42 emission factors presented in Table 8(a) are combined for natural and forced draft operation. Because emissions differ significantly depending on draft type, these factors are of limited

TABLE 6. REFINERY HEATER EMISSIONS DATA

Heater Application	Rating MW (10^6 Btu/h)	Input MW (10^6 Btu/h)	No. of Burners and Position	Fuel	Draft Type	Air Pre-heat	Conf.	NO_x ppm @ 3% O_2	NO_x ng/J (lb/10^6 Btu)	CO ppm @ 3% O_2	CO ng/J (lb/10^6 Btu)	HC ppm @ 3% O_2	HC ng/J (lb/10^6 Btu)	SO_x ppm @ 3% O_2	SO_x ng/J (lb/10^6 Btu)	Ref.
Flasher	26 (87)	29 (98)	2 x 16 V	R.G.	N	No	Double Box	88	45 (0.104)	10	3 (0.008)	1	0.2 (0.0004)	38	28 (0.064)	11
Reformer	16 (54)	7 (22)	16 V	R.G.	N	No	Box	97	50 (0.116)	11	3 (0.008)	4	1 (0.002)	6	4 (0.010)	11
Reformer	10 (35)	5 (16)	10 V	R.G.	N	No	Box	76	39 (0.091)	10	3 (0.008)	1	0.2 (0.0004)	3	2 (0.005)	11
Ultracracker Recycle Gas	16 (53)	16 (53)	16 V	R.G.	N	No	Box	103	52 (0.121)	12	4 (0.009)	12	2 (0.005)	1	1 (0.002)	11
Ultrafiner Preheat	11 (38)	15 (52)	12 V	R.G.	N	No	Box	98	49 (0.114)	13	4 (0.010)	5	1 (0.002)	6	4 (0.010)	11
Hydrotreater	20 (67)	NA	1 V	R.G.	B	Yes	Cylind.	320	163 (0.379)	17	6 (0.013)	10	2 (0.004)	180	131 (0.304)	11
Hydrotreater	20 (67)	NA	1 V	Oil	B	Yes	Cylind.	220	113 (0.262)	32	12 (.028)			460	367 (0.854)	11
Reboiler	14 (47)	NA	1 V	R.G.	F	No	Cylind.	126	113 (0.262)	17	6 (0.013)			178	129 (0.301)	11
Reboiler	14 (47)	NA	1 V	Oil	F	No	Cylind.	157	88 (0.205)	30	11 (0.026)			520	415 (0.965)	11
Process	24 (80)	18 (62)	12 D	R.G.	I	Yes	NA	333	174 (0.405)	5	2 (0.004)					12
Process	31 (106)	22 (74)	50 H	R.G.	N	No	NA	86	41 (0.096)	160	52 (0.12)					12
Crude	37 (125)	18 (60)	12 V	Oil	N	No	NA	138	76 (0.177)	4	2 (0.004)					12
Crude	44 (150)	24 (82)	10 V	R.G. & Oil	I	Yes	NA	137	74 (0.173)	0	0					12

LEGEND:
N - Natural
B - Balanced
F - Forced
I - Induced
H - Horizontal
V - Vertical
D - Downward
R.G. - Refinery Gas
NA - Not Available.

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TABLE 6. Continued

Heater Application	Rating MW (10^6 Btu/h)	Input MW (10^6 Btu/h)	No. of Burners and Position	Fuel	Draft Type	Air Pre-heat	Conf.	NO_x ppm @ 3% O_2	NO_x ng/J (lb/10^6 Btu)	CO ppm @ 3% O_2	CO ng/J (lb/10^6 Btu)	HC ppm @ 3% O_2	HC ng/J (lb/10^6 Btu)	SO_x ppm @ 3% O_2	SO_x ng/J (lb/10^6 Btu)	Ref.
Heat Medium	56 (190)	29 (97)	24 H	R.G. & Oil	N	No	NA	250	131 (0.305)	0	0					12
Coker	37 (126)	17 (58)	32 V	R.G.	N	No	NA	126	64 (0.148)	0	0					12
Flasher	36 (122)	32 (109)	32 V	R.G. & Oil	N	No	NA	207	111 (0.257)	0	0					12
Flasher	36 (122)	32 (109)	32 V	R.G. & oil	N	No	NA	166	102 (0.237)	600	237 (0.55)					12
Crude	60 (205)	69 (236)	48 H	R.G.	N	No	NA	53	28 (0.065)	604	206 (0.48)					12
Crude	60 (205)	53 (180)	48 H	R.G.	N	No	NA	120	62 (0.144)	0	0					12
Crude	28 (94)	31 (105)	14 H	R.G.	F	Yes	NA	32	17 (0.04)	379	125 (0.29)					12
Reboiler	86 (292)	49 (167)	36 H	R.G.	N	No	NA	77	40 (0.093)	0	0					12
Crude	9 (29)	19 (66)	4 H	R.G.	N	No	NA	96	49 (0.114)	0	0					12
Reformer	88 (300)	75 (256)	608 H	R.G.	N	No	NA	102	59 (0.136)	0	0					12
Reboiler	NA	33 (113)	14 V	R.G.	B	Yes	NA	264	149 (0.347)	0	0					12
Vac. Dist.	16 (56)	18 (62)	6 V	R.G.	N	No	NA	104	57 (0.133)	0	0					12
Reformer	56 (191)	92 (312)	98 V	R.G.	N	No	NA	122	68 (0.159)	0	0					12

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TABLE 6. Continued

Heater Application	Rating MW (10^6 Btu/h)	Input MW (10^6 Btu/h)	No. of Burners and Position	Fuel	Draft Type	Air Pre-heat	Conf.	NO_x ppm @ 3% O_2	NO_x ng/J (lb/10^6 Btu)	CO ppm @ 3% O_2	CO ng/J (lb/10^6 Btu)	HC ppm @ 3% O_2	HC ng/J (lb/10^6 Btu)	SO_x ppm @ 3% O_2	SO_x ng/J (lb/10^6 Btu)	Ref.
Coker	40 (137)	38 (130)	80 V	R.G.	F	Yes	Box	249	147 (0.341)	0	0					12
Crude	74 (252)	71 (241)	36 V	R.G.	N	No	NA	122	63 (0.146)	0	0					12
Reboiler	11 (39)	5 (16)	8 V	R.G.	N	No	NA	95	49 (0.114)	150	340 (0.79)					12
Reboiler	14 (47)	7 (24)	3 V	R.G.	N	No	NA	142	74 (0.171)	0	0					12
Reboiler	10 (35)	5 (18)	5 V	R.G.	N	No	NA	122	64 (0.149)	0	0					12
Crude	104 (355)	116 (394)	60 V	R.G.	N	No	NA	128	68 (0.158)	0	0					12
Crude	36 (121)	41 (141)	40 V	R.G.	N	No	NA	129	72 (0.168)	0	0					12
Crude	36 (121)	33 (114)	40 V	R.G. & oil	N	No	NA	87	50 (0.116)	19	9 (0.02)					12
Hydrocrack	57 (195)	45 (153)	45 H	R.G.	N	No	NA	67	38 (0.088)	0	0					12
Reformer	112 (383)	107 (365)	136 H	R.G.	N	No	NA	136	77 (0.179)	0	0					12
Coker	31 (104)	20 (68)	32 V	R.G.	N	No	NA	84	47 (0.110)	0	0					12
Reboiler	37 (125)	43 (146)	NA	R.G.	N	No	Cylind.	165	123 (0.285)							13
Feed Heat	24 (80)	19 (66)	NA	R.G.	N	No	Cylind.	111	81 (0.189)							13

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TABLE 6. Continued

Heater Application	Rating MW (10^6 Btu/h)	Input MW (10^6 Btu/h)	No. of Burners and Position	Fuel	Draft Type	Air Pre-heat	Conf.	NO_x ppm @ 3% O_2	NO_x ng/J (lb/10^6 Btu)	CO ppm @ 3% O_2	CO ng/J (lb/10^6 Btu)	HC ppm @ 3% O_2	HC ng/J (lb/10^6 Btu)	SO_x ppm @ 3% O_2	SO_x ng/J (lb/10^6 Btu)	Ref.
FCC Preheat	44 (150)	55 (188)	NA	R.G.	N	No	NA	160	65 (0.15)							13
Hydrocracker	57 (195)	46 (158)	NA	R.G.	F	NA	NA	257	150 (0.348)							13
Crude	62 (211)	58 (198)	NA	R.G.	I	No	Horiz.	72	34 (0.080)							13
Crude	27 (93)	37 (127)	NA	R.G.	N	No	Horiz.	104	59 (0.138)							13
Crude	23 (79)	19 (65)	NA	R.G.	N	No	Horiz.	115	66 (0.154)							13
Reboiler	26 (89)	21 (70)	NA	R.G.	N.	No	Vert.	75	41 (0.095)							13
Reformer Feed	29 (100)	35 (118)	NA	R.G.	N	No	Horiz.	125	67 (0.155)							13
Reformer	110 (375)	110 (375)	NA	R.G.	I	No	Horiz.	103	56 (0.129)							13
Splitter Reboiler	25 (84)	18 (62)	NA	R.G.	N	No	Vert.	71	35 (.081)							13
Stabilizer Reboiler	21 (70)	13 (44)	NA	R.G.	N	No	Vert.	101	49 (0.114)							13
Crude	30 (103)	34 (116)	12 H	R.G.	N	NA	NA	28	16 (0.036)							13
Crude	41 (140)	31 (106)	16 H	R.G.	B	NA	NA	75	47 (0.110)							13
Crude Vac.	18 (60)	20 (68)	12 H	R.G.	B	NA	NA	41	21 (0.049)							13

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TABLE 6. Concluded

Heater Application	Rating MW (10^6 Btu/h)	Input MW (10^6 Btu/h)	No. of Burners and Position	Fuel	Draft Type	Air Pre-heat	Conf.	NO_x ppm @ 3% O_2	NO_x ng/J (lb/10^6 Btu)	CO ppm @ 3% O_2	CO ng/J (lb/10^6 Btu)	HC ppm @ 3% O_2	HC ng/J (lb/10^6 Btu)	SO_x ppm @ 3% O_2	SO_x ng/J (lb/10^6 Btu)	Ref.
Crude	32 (110)	30 (102)	12 H	R.G.	I	NA	NA	201	123 (0.286)							13
Stripper Preheat	26 (90)	32 (108)	22 V	R.G.	N	NA	NA	79	43 (0.100)							13
Reboiler	20 (67)	25 (86)	4 H	R.G.	N	NA	NA	45	37 (0.087)							13
NA	25 (86)	19 (63)	12 V	R.G.	N	NA	NA	56	34 (0.079)							13
Reform	35 (120)	19 (65)	16 H	R.G.	N	NA	NA	89	55 (0.128)							13
Reform	29 (100)	14 (46)	20 H	R.G.	N	NA	NA	95	55 (0.127)							13
Lube Furn.	21 (70)	18 (62)	82 H	R.G.	I	NA	NA	100	58 (0.134)							13
Lube Furn.	24 (80)	21 (70)	8 H	R.G.	I	NA	NA	47	25 (0.059)							13
Hydrotreater	44 (149)	18 (60)	40 H	R.G.	N	NA	NA	104	71 (0.166)							13
NA	26 (87)	22 (76)	16 H	R.G.	N	NA	NA	102	47 (0.110)							13
Hydrocracker Feed	61 (209)	25 (86)	32 H	R.G.	N	NA	NA	106	59 (0.136)							13
Reboiler	55 (186)	43 (147)	32 H	R.G.	N	NA	NA	79	44 (0.102)							13

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TABLE 7. REFINERY HEATER EMISSION FACTORS OBTAINED FOR THE PRESENT REPORT

Application	NO_2			CO			HC			SO_2		
	No. of Data Points	Emission Factor ng/J (lb/10^6Btu)	Standard Deviation	No. of Data Points	Emission Factor ng/J (lb/10^6Btu)	Standard Deviation	No. of Data Points	Emission Factor ng/J (lb/10^6Btu)	Standard Deviation	No. of Data Points	Emission Factor ng/J (lb/10^6 Btu)	Standard Deviation
Natural Draft, Refinery Gas	42	54.8 (0.127)	17.8 (0.0413)	24	30.1 (0.07)	81.7 (0.19)	6	1.0 0.0023)	0.8 (0.0019)	5	7.8 (0.0182)	11.1 (0.0258)
Natural Draft, Oil	1	76.1 (0.177)	--	1	2 (0.004)	--	0	--	--	0	--	--
Forced Draft, Refinery Gas	14	87.7 (0.204)	59.3 (0.138)	6	22.9 (0.053)	49.9 (0.1161)	0	--	--	2	130 (0.303)	0.9 (0.002)
Forced Draft, Oil	2	100.4 (0.234)	17.3 (0.0403)	0	--	--	0	--	--	2	391 (0.910)	34 (0.079)

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TABLE 8(a). REFINERY HEATER EMISSION FACTORS OBTAINED FROM EPA-AP-42 IN ng/J (lb/10^6 Btu) (Reference 10)

Fuel	NO_x	SO_x	Particulate	CO	HC
Gas	94.2 (0.219)	819S[a] (1.905S[a])	8.2 (0.019)	Neg[c]	12.3 (0.0286)
Oil	198.2 (0.461)	460S[b] (1.069S[b])	57.6 (0.134)	Neg	9.6 (0.0223)

[a]S = Refinery gas sulfur content (lb/100 ft^3): factors based on 100 percent combustion of sulfur to SO_2
[b]S = Fuel oil sulfur content (weight percent): factors based on 100 percent combustion of sulfur to SO_2
[c]Negligible emission

TABLE 8(b). REFINERY HEATER EMISSION FACTORS OBTAINED FROM API/KVB IN ng/J (lb/10^6 Btu) (Reference 6)

Heater Type	Fuel	NO_x	SO_x	Particulate	CO	HC
Natural Draft	Gas	70.1 (0.163)	860S[b] (2S)	8.6 (0.020)	Neg[d]	12.9 (0.030)
	Oil[a]	154.8 (0.360)	627S[c] (1.46S)	78.4 (0.182)	Neg	13.07 (0.030)
Forced Draft	Gas	110.5 (0.257)	860S[b] (2.0S)	8.6 (0.020)	Neg	12.9 (0.030)
	Oil[a]	184.5 (0.429)	627S[c] (1.46S)	78.4 (0.182)	Neg	13.07 (0.030)

[a]Assumed fuel oil nitrogen content of 0.2 percent and a fuel nitrogen conversion to NO of 50 percent
[b]Refinery gas sulfur content (lb/100ft^3)
[c]Fuel oil sulfur content (weight percent)
[d]Negligible emissions.

usefulness. Also, the factors appear to be weighted toward forced draft heaters, which is not representative of the true distribution in refineries.

National emissions estimates based on fuel consumption from Table 4 and emission factors from Tables 7 and 8 are presented in Tables 9(a), 9(b), and 9(c). The combinations of draft and fuel types were assumed to be 90 percent natural draft for gas operation and 76 percent natural draft for oil operation, based on API/KVB estimates (Reference 6). It is felt that the values in Table 9(c), which are based on the API/KVB emission factors, probably represent the most accurate estimates, but this cannot be confirmed until data base information is released with the API/KVB report. As mentioned previously, tentative release of this report is scheduled for late 1978.

TABLE 9(a). 1976 NATIONAL EMISSIONS ESTIMATES BASED ON EMISSION FACTORS OBTAINED FOR PRESENT REPORT IN 10^6 kg/yr (1000 tons/yr)

Heater Type	Fuel	NO_x	SO_x	Particulate	CO	HC
Natural Draft	Gas	88.8 (96.9)	NA	NA	48.5 (53.%)	NA
	Oil	NA	NA	NA	NA	NA
Forced Draft	Gas	15.7 (17.3)	NA	NA	4.1 (4.5)	NA
	Oil	NA	NA	NA	NA	NA
Totals		NA	NA	NA	NA	NA

TABLE 9(b). 1976 NATIONAL EMISSIONS ESTIMATES BASE ON AP-42 EMISSION FACTORS IN 10^6 kg/yr (1000 tons/yr)

Fuel	NO_x	SO_x	Particulate	CO	HC
Gas	168.5 (185.6)	1.1[a] (1.2)	14.7 (16.1)	Neg	22.0 (24.2)
Oil	54.1 (59.7)	126[b] (138)	15.7 (17.3)	Neg	2.6 (2.9)
Total	222.6 (245.3)	127.1 (139.2)	30.4 (33.4)	Neg	24.6 (27.1)

[a]Refinery gas sulfur content assumed 1.83×10^{-5} kg/100 m^3 (10 grain/100ft^3) based on Federal EPA regulation (Reference 20). Natural gas sulfur content assumed zero.
[b]Fuel oil sulfur content assumed 1 percent; estimated from Reference 17.

TABLE 9(c). 1976 NATIONAL EMISSION ESTIMATES BASED ON API/KVB EMISSION FACTORS in 10^6 kg/yr (1000 tons/yr)

Heater Type	Fuel	NO_x	SO_x	Particulate	CO	HC
Natural Draft	Gas	112.8 (124.3)	1.1[a] (1.2)	13.8 (15.3)	Neg	20.8 (22.9)
	Oil	32.1 (35.4)	130[b] (144)	16.3 (17.9)	Neg Neg	2.7 (3.0)
Forced Draft	Gas	19.8 (21.8)	0.1[a] (0.1)	1.5 (1.7)	Neg	2.3 (2.5)
	Oil	12.1 (13.2)	41[b] (45)	5.1 (5.7)	Neg	0.9 (0.9)
Totals		176.8 (194.8)	172.2 (190.3)	36.7 (40.6)	Neg	26.7 (29.3)

[a]Refinery gas sulfur content assumed 1.83 x 10^{-5} kg/100 m^3 (10 grain/100 ft^3) based on Federal EPA regulations (Reference 20). Natural gas sulfur content assumed zero.
[b]Fuel oil sulfur contents assumed 1 percent; estimated from Reference 17.

SECTION 5

REFINERY HEATER EMISSIONS CONTROLS

Since CO and HC emissions are relatively low, most attempts at reducing emissions in boilers and heaters have concerned NO_x and SO_x. Consequently, this section concentrates on NO_x and SO_x control performance for refinery heaters. Control techniques which have been applied to boilers are discussed, including control efficiencies and effects on other pollutants.

The need to control nitrogen oxides from utility and industrial boilers has resulted in the development of techniques for combustion modification to reduce NO_x without disrupting operation. Table 10 lists the results of a recent survey of NO_x control efficiencies and postulated impact on other pollutants (for more information see Reference 1).

Limited data are available on applying the boiler control techniques of Table 10 to refinery heaters. Preliminary results of a recent test program (Reference 11), however, indicate that some boiler emission controls may not be directly applicable to heaters (particularly natural draft heaters). This topic is discussed below.

TABLE 10. EVALUATION OF NO_x CONTROL TECHNIQUES AND POSTULATED EFFECTS ON OTHER EMISSIONS (REFERENCE 1)

Control Technique	Resulting Combustion Conditions	Operational Impact	NO_x Reduction	CO	Vapor Phase HC	Sulfate	Organics
Low excess air (LEA)	Reduced local O_2 concentration; decreased gas velocities; increased furnace residence time	Increase in efficiency; amount limited by smoke or CO at very low EA	10% to 30% for thermal and fuel NO_x	Increased	Increased	Decreased overall because of lowered O_2 availability	Possibly increased
Flue gas recirculation (FGR)	Reduced local O_2 concentration; reduced peak flame temperature; reduced furnace residence time; increased gas velocities; more turbulent flame; increased convective zone temperature	Possible flame instability; increased vibration	20% to 50% for thermal NO_x; no effect on fuel NO_x	Possibly increased	Possibly increased	Possibly decreased	Possibly increased
Off stoichiometric combustion (OSC) including OFA, BOOS, BBF	Reduced local O_2 concentration; reduced peak flame temperature; increased convection zone temperature; delayed flame zone mixing	No major impact with new design; potential for flame instability efficiency decrease, increased corrosion (coal-fired) with retrofit	20% to 50% for thermal and fuel NO_x	Possibly increased	Possibly increased	Possibly decreased because of decreased convection zone catalysis (less volatile metal redistribution)	Possibly increased
Load reduction	Reduced flame temperature; decreased gas velocities; decreased furnace residence times; increased local O_2 concentration	Decrease in efficiency and power output; limited by spare capacity and smoke formation	0% to 40% for thermal NO_x	Decreased	Decreased	Unknown effect: Less catalyst volatilization; but greater local O_2 concentrations	Possibly decreased
Burner modifications	Control mixing of fuel and air at burner to decrease flame temperature	No major impact with new design; retrofit use constrained by firebox characteristics	30% to 60% for thermal and fuel NO_x	Possibly decreased	Possibly decreased	Possibly decreased	Possibly decreased

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TABLE 10. Concluded

Control Technique	Resulting Combustion Conditions	Operational Impact	NO_x Reduction	CO	Vapor Phase HC	Sulfate	Organics
Water, steam injection	Reduced peak flame temperature; increased local H_2O concentration	Slight decrease in efficiency; limited by CO formation; power output increases	30% to 70% for thermal NO_x	No effect	No effect	Possibly decreased	Possibly increased
Reduced air Preheat (RAP)	Reduced peak flame temperature; decreased gas velocities; increased furnace residence times; increased local O_2 concentration	Slight decrease in efficiency, increase power output	10% to 40% for thermal NO_x	No effect	No effect	Possibly decreased	Possibly increased
Ammonia injection	Increased local NH_3 concentration	Retrofit use limited, possible adverse environmental impact	40% to 70% for thermal and fuel NO_x	No effect	No effect	Possibly increased through near plume solution catalysis	Decreased with decreased particle emissions; no effect otherwise
Fuel denitrification	Reduced fuel-bound nitrogen	No adverse	10% to 40% for fuel NO_x	No effect	No effect	No effect	No effect
Fuel additives	Oxidation-promoting catalysts can help alleviate adverse side effects of other controls	Byproduct emissions formed	Generally ineffective for direct NO_x reduction	No effect	Possibly increased	No effect	No effect
Alternate and mixed fuels	Reduced fuel-bound nitrogen and/or reduced flame temperature	Varies	Varies	Varies	Varies	Varies	Varies
Flue gas treatment (FGT)	No effect	Requires temp. controls, catalyst, scrubbing soln., or oxidizing agent; possible adverse environmental impact	40% to 90% for fuel and thermal NO_x	No effect	No effect	No effect	No effect

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Table 11 summarizes recent test data on NO_x emissions from both natural draft and mechanical draft heaters. Five vertically fired natural draft heaters ranging in size from 11 to 26 MW (36 to 87 x 10^6 Btu/hr) were tested. Combustion modifications tested included fuel heat content variation, load variation, burner air register adjustment and burners out of service (BOOS).

Prior work by Bartz (Reference 12) attributed large changes in NO_x emissions to fluctuations in fuel gas composition. However, the tests reported in Reference 14 indicate that NO_x does increase with increased fuel heating value, although not significantly. The results are not conclusive, and more tests with different heaters and a wider variation in heating value are needed.

Process rate changes of $\pm$ 20 percent for two of the natural draft heaters resulted in maximum NO_x reductions of between 20 and 40 percent. The probable cause for the NO_x reduction is that excess air was reduced as the load was increased.

Staged combustion for NO_x control was attempted by adjusting the air registers and taking burners out of service. Although NO_x emissions were reduced (see Table 11), the natural draft heaters did not respond to burner adjustments as well as expected, based on previous results with other types of boilers. There are three primary reasons for this. First, in most cases the burner removal patterns increased excess air, which could not be lowered to baseline levels because of furnace pressure limits. Secondly, natural draft burners use the fuel flow to induce combustion air, which defeats the attempt to achieve staged combustion. Finally, the in-line vertically-fired burner arrangement used for most

TABLE 11. EFFECTS OF NO_x CONTROLS ON NO_x EMISSIONS FROM PETROLEUM PROCESS HEATERS (REFERENCE 14)

Heater Type	Fuel	Average Baseline NO_x		Maximum Percent Reduction in NO_x	Combustion Modification
		ng/J	ppm @ 3% O_2		
Natural Draft	Ref. Gas[a]	59	116	18	4/32 BOOS
Natural Draft	Ref. Gas	50	97	22	Air Register Adjust
Natural Draft	Ref. Gas	39	76	21	High Load, Low O_2
Natural Draft	Ref. Gas	52	103	8	2/16 BOOS
Natural Draft	Ref. Gas	49	98	24	Air Register Adjust
Forced Draft, with Air Preheat	Ref. Gas	163	320	0	Baseline Lowest O_2
	No. 6 Oil	113	222	0	Low O_2 No Effect
Forced Draft	Ref. Gas	109	214	67	Low O_2
	No. 6 Oil	88	157	8	Low O_2

[a]Refinery gas

heaters does not provide much interburner mixing, a necessary feature of staged combustion.

Two mechanical draft heaters, one with air preheat, were tested while firing either process gas or No. 6 fuel oil. Both were vertical cylindrical types and had only one burner; therefore, the only possible combustion modification was variation of excess air. As shown in Table 11, the unit with air preheat had higher emissions for both oil and gas firing. For both units, changes in excess air had little effect on NO_x emissions when firing oil. For the unit without air preheat, reductions in NO_x from 64 ng/J to 36 ng/J were achieved in one test with refinery gas when the excess oxygen was reduced from 5 percent to 2 percent.

The results of these te s, although more data are needed, indicate that mechanical draft heaters are higher in baseline emissions than natural draft heaters. However, mechanical draft heaters have combustion characteristics similar to boilers and therefore are more flexible for applying emission controls.

Several operational problems can occur when emission controls are applied to refinery heaters. Some of the possible problems include:

- Reduced efficiency (although in some cases efficiency may improve)
- Nonuniform heat generation within the furnace causing process problems and/or coking (visbreaking and thermal cracking are processes which are particularly sensitive to heat distribution)
- Upstream combustion modifications may have an affect on interdependent downstream processes
- BOOS may lead to flame impingement on tubes and therefore coking (Reference 15)

- Reduced response to load variation (Reference 15)
- Large ducts necessary for EGR are difficult for retrofit applications. Also, distribution in multiburner situations is a problem (Reference 15).

For the future, there will be several trends in refinery heater emissions and controls. To increase thermal efficiency and thereby lower fuel consumption, there should be an increase in mechanical draft and air preheat operation. Both of these will increase NO_x emissions, although, as mentioned previously, mechanical draft operation is quite responsive to emission controls.

Another possible trend is increased utilization of low NO_x burners. These burners are capable of operating at very low (close to 2 percent) excess air levels with correspondingly low NO_x emissions. Current applications have been limited to boilers, but a conversation with one manufacturer indicates that refinery heater applications are being considered (Reference 16). Other new burner designs are being investigated in an ongoing EPA-sponsored study for KVB, Inc. (Contract No. 68-02-2645).

Sulfur oxide emissions are directly related to the sulfur content of the fuel. The three techniques for controlling SO_2 from high sulfur oil are desulfurization, gasification, and flue gas treatment (FGT).

Hydrotreating is the most popular method of removing the sulfur from oil. The untreated oil is reacted with hydrogen at high temperature and pressure in the presence of a catalyst. The products are hydrogen sulfide gas and low sulfur fuel oil. The H_2S is removed by an acid gas removal column. Typically, fuel sulfur concentration is reduced by 70 to 95 percent. Over 20 different hydrotreating processes are actively in

use. The popularity of hydrodesulfurization may increase as low sulfur crude becomes less available to refineries (Reference 18).

The second technique for controlling SO_2 emissions from high sulfur fuel oil is by gasifying the oil by controlled partial oxidation with air or oxygen. The electrolytically desalted crude feedstock is partially oxidized to form a gaseous mixture of CO, H_2, CH_4, and H_2S. The product gas is then cleaned of its carbon soot, H_2S, ash, and particulate. Generally, fuel sulfur concentration is reduced by up to 99 percent. Over 200 commercial partial oxidation reactors are currently operating worldwide. The most commonly used processes are the Shell and Texaco Processes (Reference 19).

The third method of cor olling SO_2 emissions from high sulfur oil is by flue gas treatment. FGT systems consist of liquid/gas contacting chambers. The most popular scrubbing liquids are solutions of lime or limestone. Lime/limestone systems are more reliable than the other commercially available SO_2 removal systems, including double alkalai, magnesium oxide, Wellman Lord, or catalytic oxidation. The lime or limestone reacts with the SO_2 in the gas to form a mixture of calcium sulfate and sulfite, which is removed as a slurry. Use of FGT on oil-fired installations is not common, but is widespread on new coal-fired utility boilers. The maximum SO_2 removal efficiency for coal-firing is about 90 percent.

SECTION 6

REFINERY HEATER EMISSIONS TEST PLAN AND QUESTIONNAIRE

Sometime in the future, EPA may wish to supplement the data presented in this report by a combination of source testing and soliciting information from refinery heater users. This section outlines possible approaches for accomplishing these tasks.

6.1 EMISSIONS SOURCE TEST PLAN

To verify existing emission factors and to evaluate control technology for refinery heaters, an emissions testing plan has been developed and is shown in Table 12.

This test plan incorporates the major heater design variables which can affect emissions. The number of heaters of each type chosen for testing reflects the amount of available data for the particular type of heater.

Each test includes baseline and controlled (i.e., various NO_x control techniques) emissions data.

Pollutants to be sampled continuously are NO_x, SO_x, HC, and CO. Particle loading will be sampled by an EPA Method 5 sampling train. This is the EPA reference method for particulate, and is a device that draws a small sample of stack gas, removes the water and collects the particulate on filters for mass determination. Also, trace metals and organics will be measured by a Source Assessment Stack Sampler (SASS)

TABLE 12. SUGGESTED REFINERY HEATER EMISSIONS TEST PLAN

Draft Type	Air Preheat	Oil and Gas Fuel	Firing Configuration	No. of Heaters	Total Testing Hours
Forced	Yes	Gas	Vertical	2	80
Forced	Yes	Gas	Horizontal	2	80
Forced	Yes	Oil	Vertical	3	120
Forced	Yes	Oil	Horizontal	3	120
Forced	Yes	Oil and Gas	Vertical	3	120
Forced	Yes	Oil and Gas	Horizontal	3	120
Forced	No	Gas	Vertical	2	80
Forced	No	Gas	Horizontal	2	80
Forced	No	Oil	Vertical	3	120
Forced	No	Oil	Horizontal	3	120
Forced	No	Oil and Gas	Vertical	3	120
Forced	No	Oil and Gas	Horizontal	3	120
Natural	No	Gas	Vertical	2	80
Natural	No	Gas	Horizontal	2	80
Natural	No	Oil	Vertical	3	120
Natural	No	Oil	Horizontal	3	120
Natural	No	Oil and Gas	Vertical	3	120
Natural	No	Oil and Gas	Horizontal	3	120
		Grand Total Testing Hours			1920

train. This device is similar to the Method 5 train, but is specially modified to collect trace species.

Fuel analysis will include the following:

Oil Firing	Gas Firing
Higher Heating Value	Higher Heating Value
Proximate and Ultimate Analysis	Sulfur Content (refinery gas only)
Viscosity	

Proximate analysis includes API gravity, water, sediment, pour point and sulfur content. Ultimate analysis includes the concentrations of hydrogen, carbon, nitrogen, oxygen and ash. Fuel will be sampled once a day for oil and natural gas operation. Refinery gas should be analyzed once an hour, or less frequently if the data indicate that the composition is fairly constant.

The results of Section 3, which indicate that the majority of fuel consumption, and therefore emissions, is concentrated within specific process and size ranges, should be kept in mind when selecting individual heaters for testing.

6.2 QUESTIONNAIRE

In conjunction with the source testing, information on refinery heaters can be obtained through a questionnaire such as that shown in Table 13. This questionnaire would be directed toward heater users, as opposed to manufacturers. To maximize the number of returns, the questions should be straightforward and not require a large amount of research by the respondent.

TABLE 13. SUGGESTED REFINERY HEATER QUESTIONNAIRE

COMPANY NAME _____

PLANT ADDRESS _____

PLANT CONTACT _____

PLANT PRINCIPAL PRODUCTS _____

I. Heater Characterization

1. Heater Model and Plant Unit Number _____
2. Heater Application _____
3. Draft Type (Natural, Forced, Balanced, Induced) _____
4. Number of Burners _____
5. Burner Firing Configuration (upward, horizontal, downward) _____
6. Is Inlet Air Preheat utilized? _____
7. Heater Tube Orientation (vertical or horizontal) _____
8. Fuels Utilized in Heater (refinery gas, natural gas, oil, etc.)____
9. Are any of the following emissions controls utilized:

   Exhaust Gas Recirculation _____, Fuel Desulfurization _____,

   Low Excess Air _____, Staged Combustion _____,

   Fuel Switching _____, Other (specify) _____.

II. Operational Characterization

1. Rated Energy Input _____
2. Typical Operational Load Fraction August % _____

   December % _____

TABLE 13. Concluded

III. Fuel Use

1. Gas Type _____ Typical Heating Value _____

Annual Fuel Consumption for Last Year of Record _____

Fuel Consumption August _____

Fuel Consumption December _____

2. Gas Type _____ Typical Heating Value _____

Annual Fuel Consumption for Last Year of Record _____

Fuel Consumption August _____

Fuel Consumption December _____

3. Oil Type _____ Typical Heating Value _____

Annual Fuel Consumption for Last Year of Record _____

Fuel Consumption August _____

Fuel Consumption December _____

4. Other Type _____ Typical Heating Value _____

Annual Fuel Consumption for Last Year of Record _____

Fuel Consumption August _____

Fuel Consumption December _____

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